Recognition of Extended Dispatch Horizons in California's Energy Markets

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Abstract — Effective in 2009, the California ISO launched a new market structure that combines advanced unit commitment and dispatch processes with recognition of physical characteristics of the transmission system and generation resources. California's upcoming implementation of aggressive targets for renewable energy will result in new, profound changes in markets and system operations. The CAISO is responding by making additional improvements in its unit commitment processes.

***Index Terms*—look-ahead dispatch, unit commitment, renewable energy, market design**

I. Introduction

CALIFORNIA Independent System Operator (CAISO) launched a new market structure, effective in April 1, 2009, that combines advanced unit commitment and dispatch processes with recognition of physical characteristics of the transmission system and generation resources. The new market performs congestion management of firm transmission schedules, balances supply and demand, and performs other reliability functions in its system, through a financially binding day-ahead market for trading and scheduling energy, a residual unit commitment process, a real-time market that includes an hour-ahead scheduling process, market power mitigation measures, and resource adequacy requirements. Financial settlements are based on locational marginal pricing (LMP) at 3,000 or more locations in the CAISO, which are paid to generation and other dispatchable resources.

The day-ahead market co-optimizes energy and ancillary services procurement, subject to transmission and other operational constraints. There is no requirement for market participants to schedule balanced supply and demand within their own portfolios, and market participants can buy and sell from the market, subject to resource adequacy requirements. Once the CAISO has established final day-ahead schedules, the CAISO compares them to its projected load forecast, including forecasts for certain local areas, and secures additional resources through a "residual unit commitment" (RUC) process. The purpose of the RUC process is to assess the resulting gap between the scheduled and forecasted demand, and to ensure that sufficient capacity is committed or otherwise be available for dispatch in real time in order to meet the demand forecast for each hour of the next day. The day-ahead market and RUC process currently consider a 24-hour day-ahead timeframe, but as discussed in this paper, the ISO is implementing multi-day look-ahead provisions.

The real-time market updates the energy scheduling and capacity procurement, using updated demand forecasts for the next five hours, and knowledge of outages and other operating conditions. In the real-time market, a real-time unit commitment process runs on 15-minute intervals, and a separate real-time economic dispatch process runs on 5-minute intervals to determine output levels.

One fundamental feature for ensuring operational efficiency and enhance reliability is the Full Network Model (FNM) to represent the physical transmission topology and associated transmission constraints in the CAISO balancing authority area, and in balancing authority areas that are adjacent to the CAISO. The enforced transmission constraints include about 1900 flowgates and 35 nomograms, which include combinations of network flows and generation capacity, and include flowgate constraints based on temporary outage conditions. Another foundation is the state estimator, which is a component of the Energy Management System (EMS) system and provides the CAISO with a near real-time assessment of system conditions, including portions where direct measurements of real-time conditions are unavailable. The FNM and state estimator allow the real-time market to start its dispatch from the current system status, and allows the day-ahead market to base its inputs on stored state estimator solutions. Alternating current (AC) network analysis supports the security constrained unit commitment (SCUC), to ensure that interactions between real and reactive power flows are considered. Thus, SCUC minimizes bid costs while respecting the physical characteristics of selected resources and transmission constraints, considering the marginal effect of losses due to injections at each location in the grid.

Further details of the market design are provided in business practice manuals. [1]

Integrating SCUC, the FNM, and the state estimator has allowed the market optimization to ensure the feasibility of day-ahead as well as real-time schedules, and promotes consistency between day-ahead schedules and real-time energy flows. A key piece of this coordination occurs in the real-time market, which uses separate real-time unit commitment and real-time economic dispatch processes to refine unit commitment decisions quickly in response to changing system conditions, and then use the resulting unit

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commitment in a five-minute dispatch processes that again includes a look-ahead period to respond to the dynamic nature of system conditions. The look-ahead process for the real-time market is illustrated in Attachment 1. The CAISO has recognized, though, that further improvements can occur in unit commitment extending beyond the single 24-hour day-ahead timeframe, as discussed in this paper.

II. Consideration of Extended Time Horizons in Unit Commitment

Currently, the forward looking time horizon of the day-ahead market and RUC process) is the next operating day's 24 hours, taking into account the impact of prior commitment of units with very long start up times. The RUC process is able to consider unit commitment to meet the CAISO's forecasted demand for generators with up to 18-hour start-up times, but there are a small number of generators with start-up times exceeding 18 hours. The CAISO addresses this need by running an additional optimization process, "Extremely Long-Start Commitment" (ELC), following the RUC process. The ELC process gives the CAISO's operators an opportunity to determine when to commit these generators for reliability purposes, by using a 48-hour optimization period, as documented in the business practice manual for market operations [1]. However, using this manual process adds to the operators' workload and may not produce optimal schedules.

A separate issue affects generators whose start-up times are within the 18 hours that can be considered by the day-ahead market. That is, these generators are not needed in the off-peak hours at the end of the day-ahead horizon and are de-committed in one day-ahead market run, but are needed during the next day and are started again, at the expense of incurring start-up costs and possibly being unavailable in certain hours due to minimum shut-down and start-up times. This cycling can be avoided by setting their initial condition to on-line even though they do not have a previous day-ahead schedule for the final hours of the day, and letting the market optimization determine whether to keep them on-line, in which case the real-time market software would recognize that the generators have new day-ahead schedules and prevent their shut-down. To avoid instances in which this would prevent cycling of generators in cases where generation owners might prefer to cycle the generators, the ISO has considered a process enhancement that would allow the resource to inform the ISO of its intent to stay online during the cycling period. The ISO would then consider this information when setting the initial conditions for the next Day-Ahead Market. A shortcoming with this approach is that while this process would help mitigate the cycling issue, it may exacerbate over-generation conditions and result in more than an optimal amount of resources staying online during the off-peak hours. [2]

It will be more optimal for the ISO to build commitment decisions in the day-ahead market over a multi-day time horizon more directly into the market design, to allow more efficient commitment decisions that better reflect the impact of start-up costs for resources that have long start-up times. Extending the RUC process to a configurable multi-day period allows the optimization solution to evaluate if it is economic to keep a resource online during off-peak hours versus cycling the resource off based on the next day's load forecast conditions.

As discussed further below, the CAISO is implementing a 72 hour RUC process as an extension of the current RUC time horizon, by adding up to 48 hours to the current 24-hour horizon so that it spans over the next trading day, for a simultaneous run for three 24-hour market days. The 72 hour RUC process aims to provide two market benefits: (1) increase economic efficiency by reducing the commitment costs caused by additional start-up cost due to uneconomic cycling; and (2) increase grid reliability by reducing the amount of cycling of resources which results in additional stress on the resources and may increase the times when resources are unavailable. [3]

III. Details of 72-Hour RUC Process

The original day-ahead market commitment window has not been capable of effectively utilizing generators with long start-up times, which resulted in exceptional dispatch (i.e., out of economic merit order) in the real-time market. The 72 hour RUC process is intended to solve these commitment issues by using the existing SCUC market software to provide a longer commitment window. While this enhancement does not include an economic multi-day optimization for all day-ahead market passes (including market clearing and market power mitigation), it improves a generating resource's opportunity to avoid being constrained off by its minimum down time over night when it may be more efficient to remain on-line in order to more fully participate in the next day's markets.

The 72-hour RUC is achieved by extending the RUC commitment process to look ahead over a configurable default 72 hour period (TD+1, TD+2, TD+3). TD+2 and TD+3 runs have already been part of the CAISO's preparation for market operation, for purposes of anticipating market conditions and software execution issues in advance of running the next day-ahead market, but these runs have not been integrated into market results and have each considered only 24-hour horizons. This will allow:

1. For extremely long start units, i.e., units with startup times greater than 18 hours, if they are committed in the second or third trade day (TD+2, TD+3), 72 Hour RUC will provide binding commitment decisions and commitment instructions for the second and/or third trade days.
2. If an extremely long start unit are committed in the trade day (TD+2) and does not meet the minimum up time, 72 hour RUC will ensure the initial condition to be binding (on) at the end of the trade day.
3. For long start units with startup times shorter than 18 hours and longer than 4 hours, if they are committed for the last four hours of the day and are still on at the end

of the day, 72 hour RUC will ensure the initial condition to be binding (on) at the end of first trade day when running the next day's day-ahead market.

4. Operators are able to view long start and extremely long start units' commitment decisions on TD+2 and initial conditions at the end of TD+2, which can help them make future commitment decisions.

In the case of number 1 above, the commitment decision in the second trade day is binding but the energy and ancillary services bids in the subsequent day-ahead run for the second trade day can still be used to determine the optimal schedule and capacity.

In both number 2 and 3 above, the commitment decision for the second trade day is not binding, only the initial conditions are binding. This allows the subsequent day-ahead market to make sure the unit is still on at the beginning of the second trade day. However, the commitment decision, energy and ancillary service are still optimally determined by the subsequent day-ahead run for the second trade day. This also avoids having to reconsider the current RUC settlement construct and bid cost recovery associated with settlement of RUC committed resources over the 24 hour period.

The energy schedule determined in TD+2 and TD+3 of the 72 hour RUC run is kept non-binding, and will be determined by subsequent day-ahead markets.

For hours 25-72 of the 72 hour RUC process, no ancillary service requirements are enforced. Rather the CAISO may adjust its demand forecast for hours 25-72 to provide adequate committed capacity for the ancillary service capacity requirements.

The 72 hour RUC process utilizes distinct sets of DAM market bids for each of the three days in the process (TD+1, TD+2, TD+3), which are replicated from a similar day of bids submitted in the market, within the previous 7 days. For the initial day-ahead horizon, RUC will utilize the market schedules and submitted RUC availability bids, as done previously. For the TD+2 and TD+3 periods of the 72 hour RUC process, market energy bids are replicated based on best similar day. For ELC resources, the CAISO uses the submitted bids for TD+2 as these bids are already expected to be used for making ELC decisions.

The 72-hour RUC process is optional to the CAISO's operators, and may be initiated as-needed in accordance with good utility practice. The CAISO operators may run RUC for a 24-hour horizon (or 48 hours) instead of 72 hours.

For ELC resources, the commitment decisions are binding from the 72 hour RUC and are used in financial settlements, consistently with existing ELC binding and settlement rules. The only difference is the process used for ELC commitment decisions. For non-ELC resources, the initial condition is passed to the next day-ahead market, which uses that initial condition along with the bids submitted for that day-ahead market to produce schedules for financial settlements, which again is the same as the current process.

IV. Future Market Design Initiatives

As part of its ongoing work on overall enhancements to its market design, the CAISO conducts an annual stakeholder process to prioritize upcoming market initiatives, as described in [4]. The following initiatives are among those identified through that process.

Simultaneous RUC and Market Dispatch

Currently, RUC is performed after completion of the market dispatch and does not impact day-ahead market energy schedules, ancillary services, and congestion pricing and settlement. The CAISO will be considering whether to integrate the market dispatch and RUC into a simultaneous process, and if so, how.

Multi-Day Unit Commitment in the Day-Ahead Market

Currently, the day-ahead market's forward looking time horizon is one day, taking into account the impact of prior commitment of units with very long start up times as an initial condition. Making commitment decisions that look out two to three days may be able to commit resources more efficiently and better reflect the impact of startup-up cost for resources that have long start-up times. There are several design issues, including the need for bidding and bid replication rules as well as software performance and solution time requirements, which must be discussed and resolved via a stakeholder process before considering modification of the software to accommodate multi-day unit commitment in the market dispatch process itself, rather than as a subsequent RUC process. There may be limitations on the economic optimality that can be achieved by using separate market clearing, RUC, and ELC processes, but these may be unavoidable due to assumptions that bids submitted to the day-ahead market will be applicable on the following day.

Bid Cost Recovery (BCR) for Units Running over Multiple Operating Days

Currently, eligibility for BCR is determined for each operating day. Within each operating day, the revenue received for a unit net of start-up and minimum load costs is evaluated. If this net revenue value is negative, the unit is eligible for BCR for that operating day. This does not adequately consider instances in which a unit's run time crosses over from one operating day into the next. Because the BCR calculation does not determine eligibility based on the entire run time of the unit, but rather evaluates each operating day individually, it is likely that eligibility for BCR is inflated. Market participants therefore bear higher uplift charges.

The CAISO is monitoring data from the new market's operation to assess the magnitude of the issue, and may institute a change to the BCR calculation to reflect the true net revenue of units with run times that cross operating days if units operating over more than one operating day are frequently eligible for BCR in one or both days but wouldn't be eligible if their entire run time were considered, thus netting the operating days against one another.

Treatment of Use-Limited Resources with Limited Number of Hours or Start Ups

Use-limited resources accommodated in the new market are those with energy (MWh) limitations. It may be possible to incorporate software capability to accommodate other types of use limitation, including limitation on the number of hours of usage, or the number of start-ups a resource may be used for, during the scheduling horizon. Evaluating this possibility would consider whether alternatives exist for this type of functionality, since the combination of start-up time, minimum run time, and minimum down time will inherently limit the number of start-ups for a resource during a day, and the incurrence of start-up costs can cause the market optimization to minimize the number of start-ups per day.

Unit Commitment and Price Formation Improvements

The CAISO tariff establishes the objective function of the market optimization as minimization of total bid costs. Currently, however, the optimization minimizes cost based solely on point estimates of key input variables. For example, cost minimization is done on a point forecast of load in various regions, with point assumptions of generation availability and performance, point assumptions on loop flow, transmission availability and ratings. However, in reality, none of these values are known with certainty, rather the best that can be expected is an estimated distribution of possible outcomes, each with associated probabilities they will materialize. For a given set of fixed inputs, the optimization might very well produce a cost-minimized result, but actual costs are within a distribution of potential outcomes other than those assumed in the point estimate. Therefore, without taking into consideration the distribution of outcomes the robustness of the solution selected by the optimization is an unknown. To address this level of uncertainty the CAISO could consider modifications to recognize uncertainty and minimize costs on an expected basis rather than a point forecast basis.

The CAISO is aware of advancements in optimization such as stochastic unit commitment, and ongoing research is reviewing the results of applying such approaches, which will be reported in this paper's presentation. Multiple alternative approaches exist, as illustrated by two recent publications. Tuohy et al apply a method of rolling unit commitment to incorporate updated forecasts of wind power, by repeating a deterministic unit commitment with 24-hour look-ahead periods, at more frequent intervals (e.g., every six hours) than would otherwise be used, and demonstrate the potential for reduced system operating costs while maintaining reliability. [5] This method may be comparable in some ways to the real-time unit commitment process used by the CAISO, as presented in Attachment 1, by repeating a 5-hour look-ahead period on one-hour intervals.

An approach with further similarity to the end-to-end CAISO market process is developed by Papavasiliou, Oren, and O'Neill. [6] This approach is a two-stage stochastic programming model for committing reserves in systems with large amounts of wind power, using multiple scenarios to represent plausible real-time operating conditions including variability of renewable generation output, when making unit commitment decisions in a timeframe when there is uncertainty about what the actual real-time conditions will be. This model uses a two-stage stochastic unit commitment algorithm for determining reserve requirements in the presence of wind power. Its results demonstrate the model's improvement over other methods of determining reserve requirements in the presence of uncertainty. A notable feature of this approach is the similarity of the two-stage algorithm to the sequence of the CAISO market, in which the day-ahead market determines the unit commitment for generators with start-up times of five hours or longer and procures the CAISO's forecasted amount of ancillary services, followed by the real-time market when shorter start-up generators are committed, unanticipated ancillary service requirements are met, and the final dispatch is scheduled.

Acknowledgment

The CAISO's work on integration of renewable energy resources extends throughout multiple departments of the CAISO, and the background information that is presented herein is the product of previous analyses presented by CAISO staff. The authors thank the CAISO staff members who have contributed to these projects.

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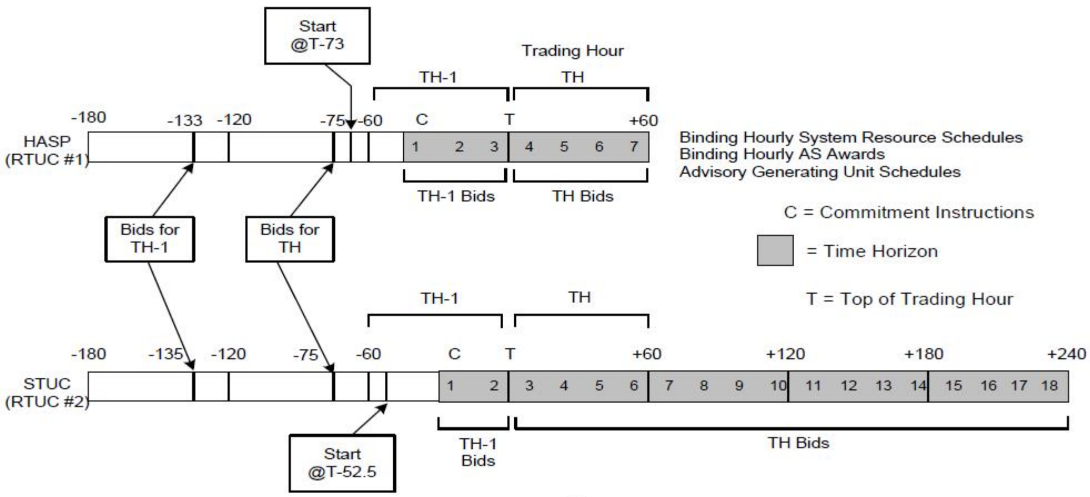
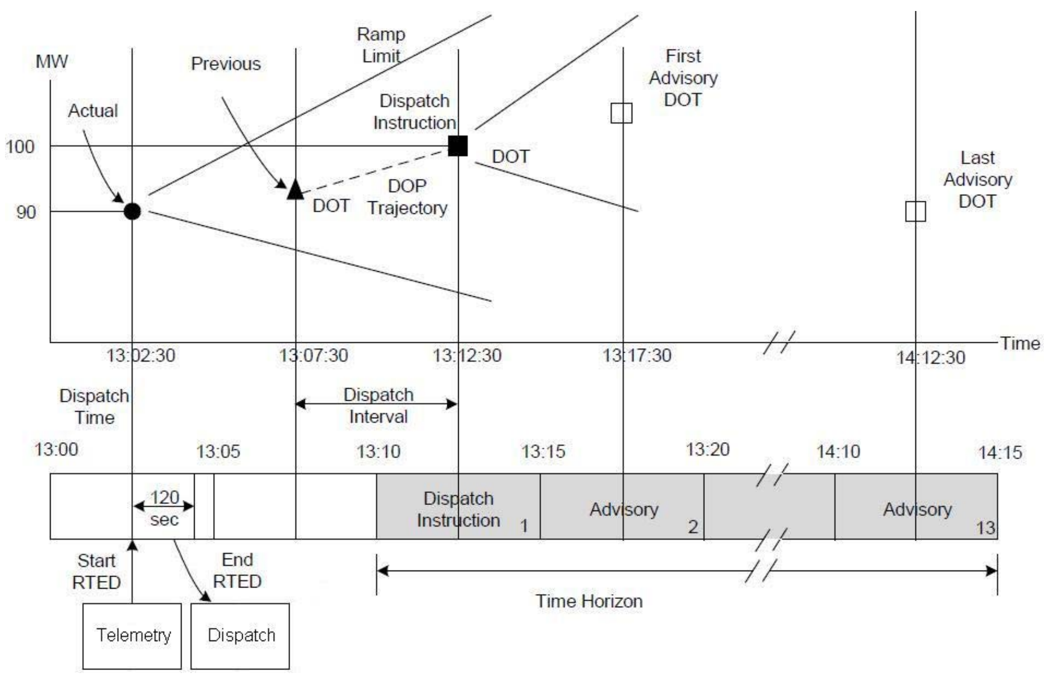
ATTACHMENT 1. REAL-TIME MARKET TIMELINES.

The CAISO’s real-time market includes two processes to achieve an extended time frame for unit commitment decisions and economic dispatch: (1) Real-Time Unit Commitment (RTUC), which includes the Hour-Ahead Scheduling Process (HASP) for hourly intertie scheduling, runs on 15-minute intervals, and (2) a separate Real-Time Economic Dispatch (RTED) process runs on 5-minute intervals to determine output levels. [7]

The RTUC run that includes HASP uses seven 15-minute intervals to achieve nearly a two-hour look-ahead period, and the subsequent RTUC run uses 18 15-minute intervals to achieve nearly a five-hour look-ahead period. Subsequent RTUC runs in each hour consider four to five 15-minute intervals. This allows start-up decisions for resources with start-up times less than five hours to not require commitment in the day-ahead market, when there is greater uncertainty about real-time operating decisions, as shown here:



RTED runs then use the unit commitment from RTUC, combined with current operating points, to realistically dispatch resources with knowledge of upcoming system conditions from the RTUC process:



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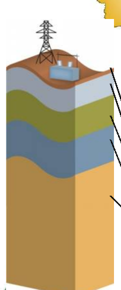
California ISO provides open, non-discriminatory access to transmission grid



1.8% coal
12.2% large hydro
13.9% hydro, geothermal, biomass, wind, solar
15.3% nuclear
56.7% natural gas

Source: 2009 Total Electricity System Power, California Energy Commission

Responsibilities:

- Reliability, grid planning, outage coordination
- Market development, operations, monitoring

CAISO manages approximately 80% of California's electricity load

- 55,183 MW in-state power plant capacity
- 10,000 MW import capacity
- 50,270 MW record peak demand (7/24/2006)
- 25,526 circuit-miles of transmission lines
- 30 million people served
- 286 million annual megawatt-hours of electricity delivered annually
- 38,000 generation & transmission outages per year
- Over 30,000 day-ahead market transactions per day, similar volume for real-time market

Page 2

CAISO markets match supply & demand for reliability in day-ahead through real-time

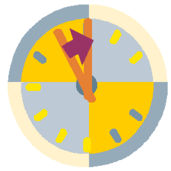
Day Ahead Market

Hourly market for 24 hours of next day

Establish energy and ancillary service schedules

Manage congestion (transmission access) using Full Network Model (FNM)

Determine residual unit commitment requirements



Hour Ahead Scheduling

Prior to real-time (RT) market, schedule energy and ancillary services for static interchange for 24 individual hours

Manage congestion using FNM

As one of 4 RT pre-dispatch processes, establish unit commitment & advisory schedules for internal & dynamic resources

Real Time Market

Manage energy flows on transmission grid with telemetry and 1-minute state estimator solutions

Update FNM for RT conditions

Dispatch balancing energy/ ancillary service

Changes over the next 10 years present operational challenges

- Over 20,000 MW of wind and solar capacity is expected to be interconnected by 2020 – Increased supply volatility
- Approximately 18,000MW of thermal generation will be repowered or retired in next 10 years – Uncertainty surrounding thermal resources
- Potential changes to load patterns as a result distributed generation and electric vehicles – Changing less predictable load patterns

California ISO
Shaping a Renewed Future

20% and 33% Renewable Portfolios Standards lead to significant new resources

	Biogas/ Biomass	Geo-thermal	Small Hydro	Solar Thermal	Solar PV	Wind
2006 Reference Case	701	1,101	614	420		2,648
Reference Case with 20% Renewables	701	2,341	614	2,246		6,688
Reference Case with 33% Renewables	1409	2,598	680	6,902	5,432	11,291

33 % solar PV includes 2,262 MW of customer side PV

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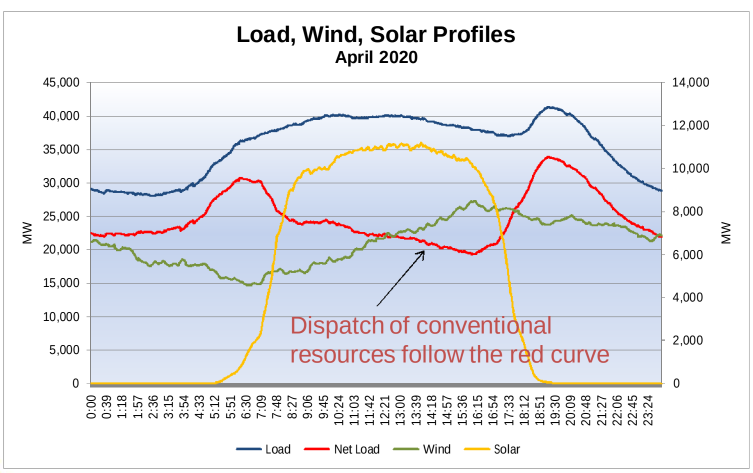
Dispatch of conventional resources would not follow the typical load curve



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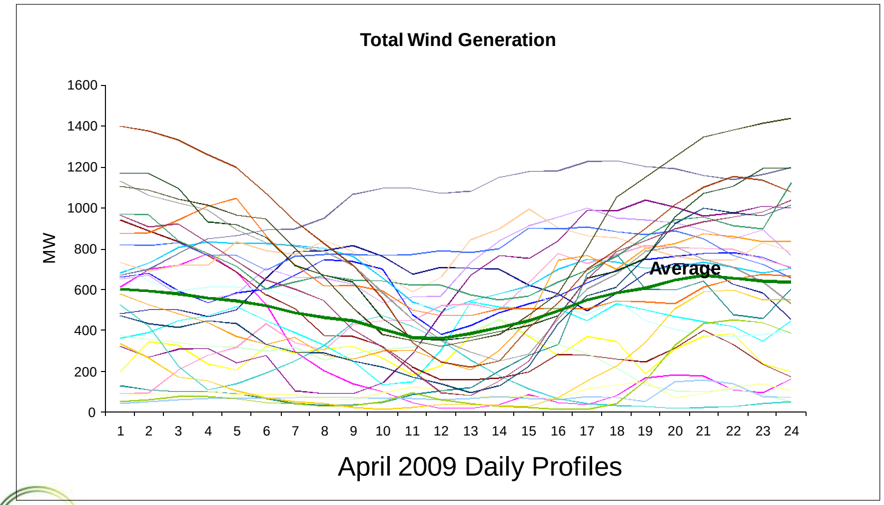
Wind production varies greatly from day to day, and intra-day



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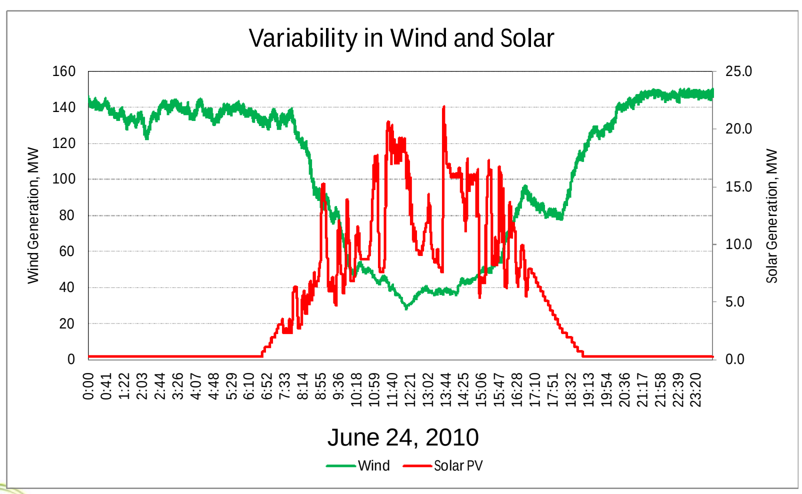
Wind and solar resources can vary significantly within days



A 150 MW wind plant and a 24 MW solar resource

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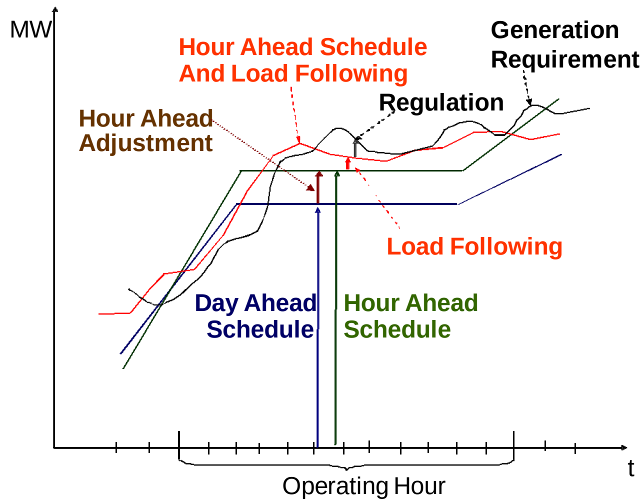
Increased supply variability requires flexibility in dispatch of controllable resources



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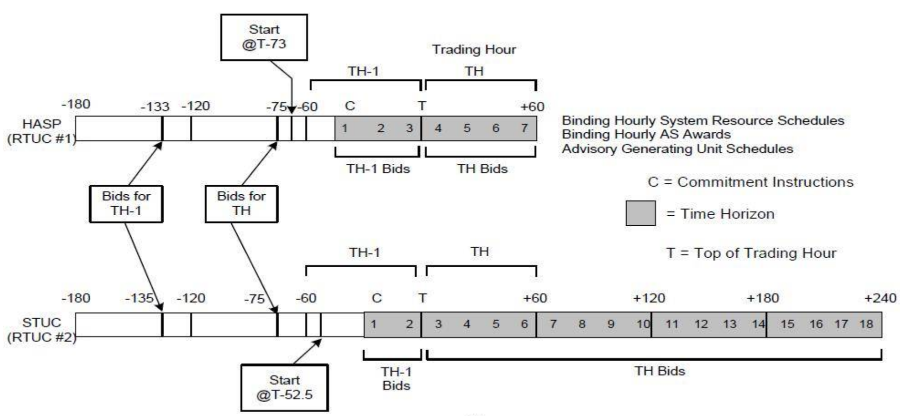
Real-Time Unit Commitment (RTUC) prepares for Real-Time Economic Dispatch



HASP = Hour Ahead Scheduling Process
STUC = Short Term Unit Commitment

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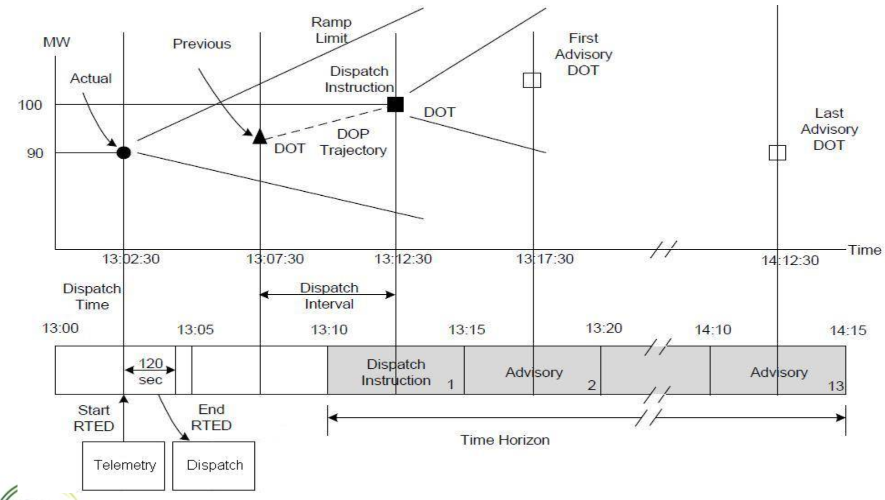
Real-Time Economic Dispatch (RTED) meets energy balance in 5-minute intervals



Operational and market enhancements support renewable integration

- Operational Enhancements
  - Wind & solar forecasting tools (output, ramping requirements)
  - More sophisticated grid monitoring systems
  - Over-generation mitigation procedures
  - Coordination with neighboring balancing areas
  - Generation interconnection standards
  - Pilot projects (storage, synchrophasors, demand response)
- Market Enhancements
  - New market products & changes to market rules
  - Increased regulation and reserve requirements
  - More sophisticated day-ahead unit commitment algorithms

Existing processes: Extremely Long-Start Commitment (ELC) provides longer horizon

- Residual Unit Commitment (RUC) considers up to 18-hour start-up
- ELC follows RUC, with 48-hour commitment
  - Allows operators to consider start-up of a subset of generators
- ELC still has shortcomings
  - Adds to operator workload, may not be optimal
  - Manual steps address cycling issues but may exacerbate over-generation

Enhancements now in progress to improve process

- 72-hour RUC process
  - Extends RUC to multi-day optimization, to determine whether generators remain on-line
  - Binding commitment & financial settlement consistent with existing ELC rules
- Flexible ramping constraint
  - Proposal in stakeholder process: RTUC will ensure sufficient upward ramping capability for RTED
  - Compensation based on opportunity costs

CAISO's annual prioritization of future initiatives considers future enhancements

- Potential future enhancements in prioritization process include:
  - Simultaneous RUC & market dispatch
  - Multi-day commitment in day-ahead market
  - Bid cost recovery changes for units running over multiple operating days
  - Consideration of limited run time or start-ups
  - Unit commitment and price formation improvements

Illustration of analysis leading to consideration of potential changes

- Example: unit commitment improvements
  - Model from competitive path assessment, using stochastic unit commitment in PLEXOS software
- Initial results suggest analysis needed before reaching conclusions:
  - Average cost of $54.82/MWh with standard optimization compares to $54.51 with day-ahead stochastic optimization, vs. $55.32 in stochastic analysis if real-time resources restricted to those committed in standard day-ahead commitment